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Techno-economic Appraisal of Fossil-fuelled Power Generation Systems with Carbon Dioxide Capture and Storage

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ABSTRACT

Carbon capture and storage (CCS) facilities coupled to power plants provide a climate change mitigation strategy that potentially permits the continued use of fossil fuels whilst reducing the carbon dioxide (CO₂) emissions. This process involves three basic stages; capture and compression of CO₂ from power stations, transport of CO₂, and storage away from the atmosphere for hundreds to thousands of years. Potential routes for the capture, transport and storage of CO₂ from United Kingdom (UK) power plants are examined. Six indicative options are evaluated, based on 'Pulverised Coal', 'Natural Gas Combined Cycle', and 'Integrated (coal) Gasification Combined Cycle' power stations. Chemical and physical CO₂ absorption capture techniques are employed with realistic transport possibilities to 'Enhanced Oil Recovery' sites or depleted gas fields in the North Sea. The selected options are quantitatively assessed against well-established economic and energy-related criteria. Results show that CO₂ capture can reduce emissions by over 90%. However, this will reduce the efficiency of the power plants concerned, incurring energy penalties between 14-30% compared to reference plants without capture. Costs of capture, transport and storage are concatenated to show that the whole CCS chain 'cost of electricity' (COE) rises by 27-142% depending on the option adopted. This is a significant cost increase, although calculations show that the average 'cost of CO₂ captured' is £15/tCO₂ in 2005 prices [the current base year for official UK producer price indices]. If potential governmental carbon penalties are introduced at this level, then the COE would equate to the same as the reference plant, and make CCS a viable option to help mitigate large-scale climate change.

KEYWORDS: Electricity generation; Fossil fuels; Power plants; Carbon capture and storage (CCS); Economics; Environmental impacts

1. INTRODUCTION

Energy sources of various kinds heat and power human development, but also put at risk the quality and longer-term viability of the biosphere as a result of unwanted, 'second order' effects [1]. Arguably the principle environmental side-effect of electricity generation is the prospect of global warming due to an enhanced greenhouse effect induced by combustion-generated pollutants [1-4]. Carbon dioxide (the main 'greenhouse gas'; GHG) is thought to have a

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'residence time' in the atmosphere of around one hundred years. CO₂ accounts for some 80% of the total GHG emissions in the United Kingdom (UK), and the energy sector is responsible for around 95% of these [1]. In the UK it is projected that present strategies to combat global warming will reduce carbon dioxide (CO₂) emissions to close to the 'domestic' target of a 20% fall by 2010 compared with the 1990 levels [1,4]. However, this is a modest achievement compared with the worldwide requirement to cut down GHG emissions by more than 80% in order to stabilize the climate with a moderate 2°C temperature rise by 2050 [4]. In the European Union (EU), CO₂ emissions are projected to increase by 3–4% by 2010 compared to 1990 levels. This increase is dominated mainly by a rise of some 25% in carbon emissions in the transport sector compared over 1990 levels. For this reason, electric vehicles may be a potentially attractive option in the future, provided that the associated power networks are decarbonised.

In addition to climate change, there is also a widespread concern over energy security and the dependence on limited fossil fuel resources [such as coal, oil and natural gas (NG)], especially in the industrialized nations. Coal, one of the world's most abundant fossil fuel sources, currently meets about 23% of the total world primary energy demand, some 38% of global electricity generation, and is an important input for steel production via the basic oxygen furnace process that produces approximately 70% of world steel output [4-6]. But tougher environmental/climate change regulations mean that coal will have to reduce its environmental impact if it is to remain a predominant energy source. In contrast, NG can play a significant part in reducing GHG emissions [1-2,4,8]. Worldwide, advanced coal conversion systems and carbon sequestration technologies capable of removing CO₂ from the flue gases of fossil fuel-fired power plants are now being investigated as a matter of some priority [3,9-17]. Pressurised fluidised-bed boilers, for example, yield high combustion efficiencies together with NO_x emission control [1]. The US *Department of Energy* (DOE) has instigated a major research programme aimed at developing new carbon sequestration technologies. Japanese industry (see, for example, Tsuge and Matsuo [18]) is well advanced in terms of demonstration plant for CO₂ sequestration, as well as for other pollutants. These 'cleaner coal' power generation plants include Integrated Gasification Combined Cycles (IGCC) [3,9-10,12-13,15-16] and so-called 'hybrid combined cycles'. IGCC plants lead to both relatively high thermal efficiencies (greater than 50%) and a reduction of CO₂ of better than 20% compared to conventional plant [1]. This range of cleaner coal systems provides the possibility of a transitional technological pathway out to a period when humanity can (hopefully) rely on low or zero carbon energy systems.

The present contribution is part of an ongoing research effort aimed at evaluating and optimising the performance of energy systems. Here the potential routes for the dehydration, capture, transport and storage of CO₂ from UK fossil-fuelled power plants are examined. Six possible (or 'indicative') options are evaluated, based on Pulverised Coal (PC), Natural Gas Combined Cycle (NGCC), and IGCC power stations. Chemical and physical CO₂ absorption capture techniques are employed with realistic transport scenarios to Enhanced Oil Recovery (EOR) sites or depleted gas fields in the UK sector of the North Sea. The selected mature (rather than 'first of a kind') technological options are quantitatively assessed against well-established economic and energy-related criteria. It builds on an earlier study of the thermodynamic and 'exergoeconomic' performance of NGCC plant with and without carbon capture by Hammond and Ondo Akwe [8]. Although the focus in the present work has been on the UK context, the findings have much broader implications for the adoption of clean power technologies in an international perspective.

2. CARBON CAPTURE AND STORAGE TECHNOLOGIES

2.1 Capture

Pulverised Coal and Natural Gas Combined Cycle plants are currently operational in the UK and globally. In addition, IGCC plants are being introduced into the global market. There are three generic systems that may be used to capture CO₂ from these three types of power stations. Post-combustion capture separates CO₂ from the exhaust (flue) gas after combustion. This system typically exploits chemical solvents such as amines [3,8-9,12,15-16], like mono-ethanolamine (MEA), to absorb the CO₂. This is the most common method of capture, and therefore has the most operational experience. However, the low concentration of CO₂ in the flue gas inhibits the capture process. It therefore requires powerful chemical solvents and large-scale processing equipment in order to handle the emissions. This is both a costly and energy intensive process. Nevertheless, it offers significant potential for the retrofitting of capture systems to current PC systems and, for that reason, it is favoured by the UK Government [14,17,20-21]. Pre-combustion capture [3,12,15-16] separates CO₂ from the gas stream before combustion, where the concentration of CO₂ in the gas stream is high. This aids the capture process and enables less selective capture techniques, such as physical absorption using ‘Selexol’. The quantity of gas involved is lower, reducing the need for large equipment, and this can reduce the energy requirements. But the process involves more drastic changes to the power station. Oxy-fuel combustion capture [3,12,15-16] involves combustion of fuel in oxygen instead of air. This produces a gas rich in CO₂ that aids the capture process significantly. The process is nonetheless expensive, and is presently only at the demonstration phase. Research is currently examining more effective chemical and physical absorbents, as well as the development of novel capture techniques. The latter include new adsorbents, membranes and cryogenics that may lower the costs and energy penalties associated with carbon capture [3,15-16].

2.2 Transport

The transmission of CO₂ after capture is required, except where plants are located directly above a geological storage site [3], in order to deliver the CO₂ to storage sites for injection away from the atmosphere. It is normally required to be compressed to a pressure of about 8 MPa [3] and/or cooled [11], which implies further energy inputs and a reduction in net carbon savings. In the quantities necessary for a large-scale CO₂ transport network required for CCS, bulk CO₂ transport can only be achieved viably using shipping tankers or a pipeline network [11]. There is extensive knowledge and experience in the North America for piping CO₂. More than 3000 km of pipelines are currently used in that part of the world for the transport of several Mt of CO₂ to EOR sites [11]. Much can be learned from this experience, as well as from the current UK natural gas distribution network operated by *National Grid* [17]. Stakeholders feel that there are no long-term technical barriers to the development of a CO₂ pipeline network in the UK [17]. However, existing oil and natural gas pipelines out into the North Sea are reaching the end of their engineering life, and were designed for rather different operating conditions. In addition, it will be necessary to devise new metering devices to monitor the quality of the dense phase CO₂ [17]. A CO₂ pipeline operator runs a significant financial risk [17], because of the high cost of the assets and low returns. Indeed, Gough *et al.* [17] suggest that the cost increase between a network and alternative transmission means could be as high as £3 per tonne. Shipping becomes more economical than piping for the transport of CO₂ over long distances (>1000 km). Liquefied CO₂, which has similar properties to LPG [3], can be shipped overseas at a pressure of around 0.7 MPa on a commercially attractive basis.

2.3 Storage

Methods for storing CO₂ away from the atmosphere could potentially involve storing CO₂ under the ground, under the ocean, in solid carbonates, and in industrial products. Geological storage is currently the most viable option [17]. Potential methods include storage in depleted oil and gas

reservoirs, deep saline formations, and depleted coal seams. EOR and Enhanced Coal-bed Methane (ECBM) techniques can provide revenue to offset costs for oil reservoirs and coal seams respectively. Other methods include salt caverns, abandoned mines, basalts, and oil/gas shales. These options only offer small storage capacities, and have not been studied to the extent of the main geological methods. Currently the most attractive geological option is EOR. This is a mature process that has been used widely in the US [3]. It involves the injection and storage of CO₂ into oil fields that are coming to the end of their useful life. This delays costly oil field decommissioning, and can utilise the existing infrastructure of the oil well. In addition, the extra oil captured due to the injection of CO₂ can be sold for financial gain, which depends on the oil price. Enhanced Gas Recovery (EGR) is another option, but it could only increase the recovery rate by around 5 per cent compared to levels of 15 per cent for EOR. Depleted oil and gas wells offer a significant global storage capacity (~130 GtC [9]), and they offer potential storage permanence because they have stored hydrocarbons before they were turned into production wells. The capacity of depleted oil/gas reservoirs alone is not enough to mitigate global climate change: global carbon emissions amounted to 6 GtC per annum in 2000 [9]. The storage capacity of saline formations is far greater. There has been one major storage project undertaken in a saline formation in the Norwegian sector of the North Sea: the Sleipner field [3,9]. Monitoring suggests that no CO₂ has currently escaped. However, the monitoring of saline formations is a lot less well-developed than in the case of oil and gas wells. The confidence in the permanence of storage is consequently lower, especially because the majority of the potential storage is in ‘open saline formations’ that provide an eventual escape path for CO₂. More development is required in these cases to simulate options and determine whether the CO₂ will be held over hundreds to thousands of years in order to mitigate climate change. The displacement of methane by injected CO₂ in coal seams that cannot readily be mined is another geological option. This has the advantage of storing CO₂, whilst retrieving economically valuable methane. It is still in the demonstration phase and, even though its storage capacity is relatively low, it could play a part in large-scale CCS if the economics can be accurately determined; currently there is a wide range of estimated costs associated with ECBM. Oceanic storage offers the greatest storage potential, but it is still in the research phase due to uncertainties about the permanence of storage and widespread public and legal obstacles. If these can be overcome it could play a significant part of CCS schemes in the future. Mineral carbonation is a process that involves the reaction of minerals with CO₂ to produce solid carbonates that can permanently store CO₂ away from the atmosphere [8]. However, this process produces a vast amount of waste material and is currently not economically viable. If geological and oceanic storage opportunities are proved to lack the type of permanence required for storage, then it could be an option in the future – provided the costs are cut dramatically as research and development progresses. Storage of captured CO₂ in industrial products offers little potential for use in a large-scale CCS scheme. The storage capacity is small, and its permanence appears to be far too short to seriously aid the mitigation of climate change.

2.4 CCS Process Characterisation, Innovation, and Deployment

The maturity of the CCS processes is characterised in Table 1. The current knowledge of CCS elements is ranked according to this technological maturity. ‘Research’ indicates a process that is currently undergoing simulation trials, but is not yet reached significant development or demonstrations. ‘Demonstration’ processes are those that have undergone post-research development via, for example, pilot-scheme projects. In the UK the Government aims to encourage the development of four CCS demonstrators in operation by 2014-2015 [14,17,20-21], with commercial retrofits being introduced after 2025 on a pre-commercial basis. The EU aims to select 12 CCS demonstration projects for operation across Europe by 2015 [14,17]. ‘Commercialisation’ reflects the introduction of processes into a fully competitive market.

Table 1: Global state-of-the-art of CCS technologies (*Source:* adapted from the 2005 IPCC Special Report on CCS [3])

CCS element	CCS process	Research	Demonstration	Commercial	Mature
Capture	Post-combustion				
	Pre-combustion				
	Oxy-fuel combustion				
Transport	Pipeline				
	Shipping				
Geological storage	Depleted oil/gas fields				
	EOR				
	Saline formations				
	ECBM				
Oceanic storage	Dissolution type				
	Lake type				
Other storage	Mineral carbonation				
	Industrial usage				

Finally, ‘mature’ processes are those that have displayed operation in the market over reasonable period. The UK *Parliamentary Office of Science and Technology* (POST) recognise that current commercial CCS operations are all at a much smaller scale than is required for (say) a 500 MW coal-fired power station [12]. Even the largest plant in the USA (at Trona in California) is less than 10% of the capacity needed for such a large-scale power station [12].

There is a large body of literature concerning innovation and innovation theory [22]. The UK *Department of Transport* (DfT) [23] have presented a useful, but simplified, representation of the process of innovation (that they attribute to the *Carbon Trust*; see Fig. 1 [22]). This incorporates the various actors and institutions, together with the relationships between them. It implies a linear process (from basic R&D to the diffusion of a commercial technology), although it is important to emphasise that innovation is a dynamic, non-linear process; as acknowledged by the DfT [23]. Thus, the full picture is more complex, as feedback loops exist between the different stages and there are important links between technological and institutional change that must be considered. A whole-systems perspective of the innovation process is therefore appropriate (as opposed to considering each stage in isolation), and it is from such a perspective that policy guidance should be drawn. The market penetration of a (successful) new technology typically varies in the manner of the hypothetical S-shape, or ‘logistic’, curve [24–25] shown in Fig. 2 [22]. Take-up of the technology begins slowly, then as commercial viability is reached production ‘takes off’, and finally the technology rapidly diffuses before gradually slowing down as the market saturates. A ‘roadmap’ for the deployment of CCS in the UK has recently been devised by Gough *et al.* [17] on the basis of a two-stage process involving a CCS landscape review and a ‘high-level’ (i.e., ‘expert’) stakeholder workshop. They envisage that the development phase

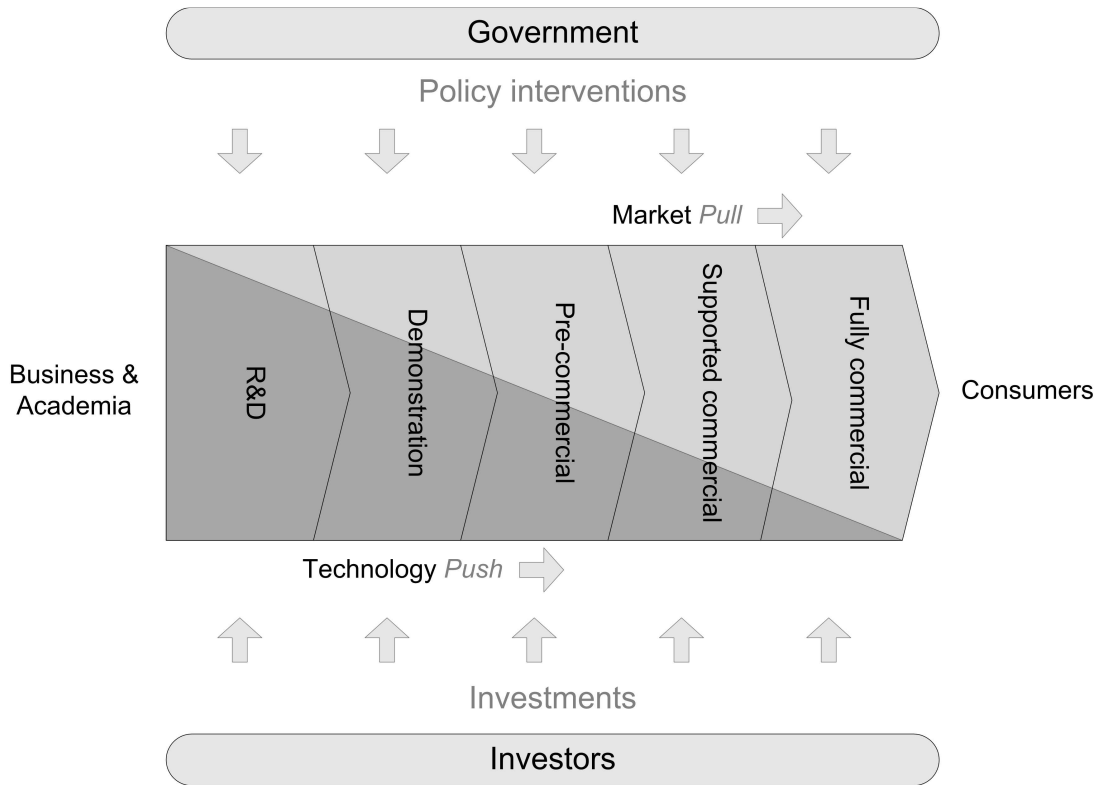


Fig. 1. The ‘innovation chain’ and its ‘actors’. (Source: Allen *et al.* [22]; adapted from the UK Department of Transport [23])

would extend over the period to 2015, followed by commercialisation out to 2050. The cost of production of a technology tends to reduce as production volumes increase; a phenomenon reflected by so-called technology ‘*learning curves*’ or ‘*experience curves*’ [26-28]. The development of a variety of electricity-generating technologies within the EU [26] is illustrated in terms of such curves in Fig. 3 [22]. The causes of cost reduction vary, but can include ‘learning by doing’ improvements and economies of scale. It is therefore clear that higher costs for new technologies present a barrier to entry when competing with established technologies. This contributes to the ‘lock-in’ of incumbent technologies, and highlights the path dependence of development; both of which can discourage innovation [22]. In order to promote innovation and create a market for diverse technology options, these processes must be considered in the context of policy-making.

The appropriate policy instruments will vary with the stage of a technology’s development [22]. The dynamic nature of innovation suggests that each instrument will influence the market interactively and thereby the effectiveness of other policies. Some prevalent energy policy strategies are indicated in Fig. 2 [22], and will be discussed below in the context of the UK CCS deployment. The various types of market intervention include, firstly, *R&D support* [22,29]. Here research programmes and grants (or tax credits) encourage public, academic and private R&D and ensuring a supply of trained scientists. Over the period 1974 – 2004 there was a significant downward trend in both public and private R&D expenditure in OECD countries, which correlates broadly with oil price trends [30]. The UK Government’s Stern Report [31] on the economics of climate change, jointly sponsored by the Cabinet Office and the HM Treasury, called for a doubling of global public energy R&D funding (to around £13 billion) for the development of a diverse portfolio of technologies, which represents a drastic increase compared to past decades (of around £6 billion). *Technology subsidies* [22,29] include demonstration

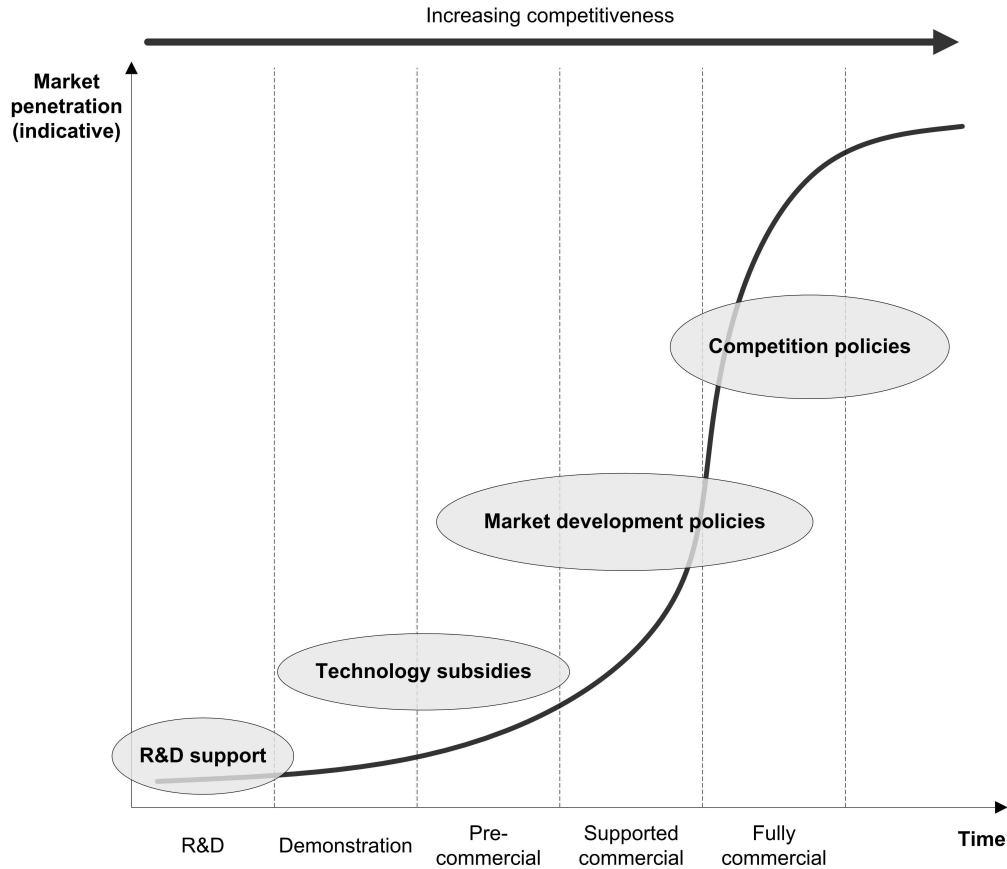


Fig. 2. S-curve of technology development and policy categories. (Source: Allen *et al.* [22]; adapted from Foxon *et al.* [24] and Midttun and Gautesen [25])

project funding and support for early stage commercialisation. The Stern Report [31] advocated a two to five-fold increase in deployment incentives from current levels of around £20 billion (in addition to measures aimed at strengthening the carbon price). *Market development policies* [22,29] include feed-in tariffs, specialised auctions, tax credits, accelerated depreciation, and the creation of niche markets. Under these policies new, low carbon technologies can develop with a degree of protection from the mainstream energy markets; permitting simultaneous development of a range of technologies. Moving in the direction of increasing competition are niche market policies, such as tradable certificates [22]. The market is then left to determine the price of certificates, which can lead to price uncertainty (and increased risk to investors [29]), but also promote cost-efficient solutions. Inter-technology certificate markets risk encouraging technological lock-in of the short-term cost-efficient technology. Therefore if diversity of supply is required, niche markets for specific technologies are more appropriate, as they are protected from alternatives during development. The Stern Report [31] advocated the use of CCS ‘portfolio standard’, beginning with a very low proportion of such plant (e.g., 0.5%) in the demonstration phase. Midttun and Gautesen [25] argue, based on the results of the EU research project ‘REALISE’, that instruments like feed-in tariffs and market certificates should not be seen as competing alternatives, but rather as complementary policy steps in the technology development cycle, or ‘technology pipeline’ [32], outlined in Fig. 2 [22]. Finally, *competition policies* [22,29] are appropriate for technologies approaching maturity, and include higher-level certificate markets, third party access policies and corporate governance policies [25]. The aim is to create support that is sufficient for furthering commercialisation of technologies towards full competitiveness in the mainstream energy market, whilst providing cost-effective energy to

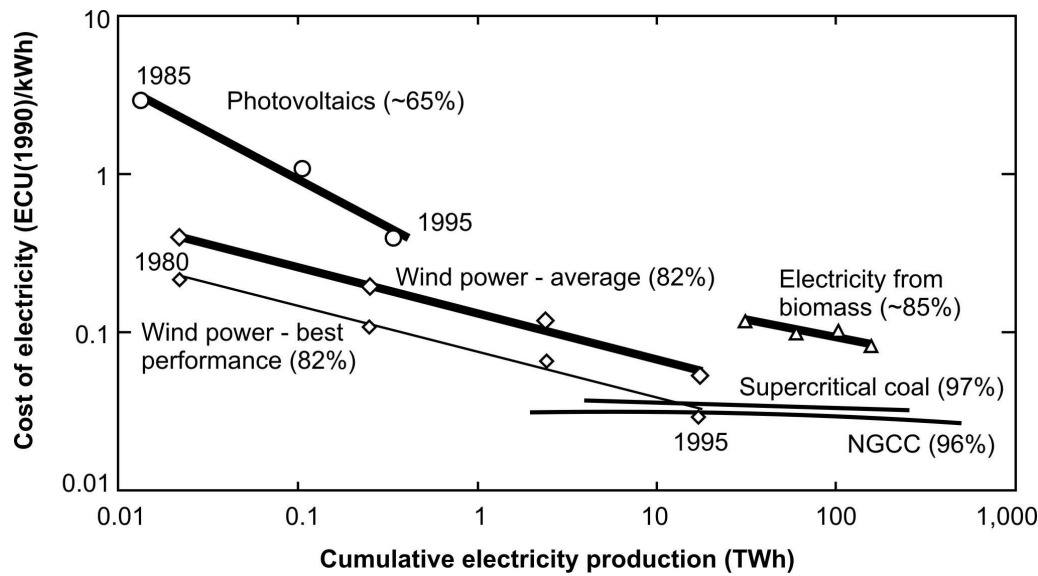


Fig. 3. Experience curves for electricity-generation technologies in the EU, 1980 – 1995.
(Source: Allen *et al.* [22]; adapted from the IEA [26])

consumers [22]. Scrase and Watson [29] concatenate these various types of market intervention into just two categories: *upfront subsidies* (such as grants and tax breaks for developers) and *performance incentives* (such as guarantees on the electricity and/or carbon price that a CCS project might secure).

A diverse range of energy policy instruments can be used to support the UK Government's aim of securing clean, diverse, reliable, and cost-effective energy supplies [2,4]. There can be tensions between such objectives; for example short-term cost-efficiency may conflict with diversity of supply [22]. Whatever the chosen approach to technological innovation and deployment, the recent literature [24,31-32] highlights the paramount importance of a stable, consistent, long-term framework from governments. Political aspirations are not seen as sufficiently 'bankable' by industry, and policy therefore needs to be designed to send clear, investment-inducing signals to business. Indeed, the UK CCS stakeholder workshop held (in May 2007) by Gough *et al.* [17] indicated that several of the industry representatives were concerned that the UK Government was failing to provide sufficient enabling technology 'push' (see Fig. 1 [22]) across the entire CCS chain. Policies should also have a clear review process and exit strategies for fully competitive technologies [31]; further reducing risk for investors. Closer collaboration between government and industry is called for in the Stern Report [31], which saw the development of a shared vision between government, industry and research community as of vital importance [24]. The Stern Report also advocated a realistic carbon price as a vital part of future policy; indeed it argued that failure to take account of environmental externalities (such as climate change) ensures that there will be under provision and slower innovation [31]. However, carbon pricing is still in its infancy [22], and even where it is implemented uncertainties remain about the durability of the price signals over the long term. The EU *Emissions Trading Scheme* (ETS) has shown considerable volatility in terms of the carbon price over recent years [17,19] and has been generally much lower than is required to encourage the take-up of low carbon energy technologies. The first UK CCS demonstrators are likely to come on stream during the third trading phase of the ETS [17]. Incentivisation of subsequent plants would require an *adequate* carbon price, which would be critically dependent on there being tighter National Allocation Plans under the ETS. Regulation and alternative policy

approaches (such as some of those mentioned above) are therefore vital to promote the required investment in sustainable technology innovation [22].

3. CCS PERFORMANCE AND ECONOMIC ASSESSMENT FOR THE UK

3.1 Carbon Capture and Storage Options for the UK

In order to estimate the current potential of CCS in the UK a set of the most likely technological options were identified, along with assumptions and appropriate data requirements. PC and NGCC plants are the main types of electricity generation systems in the UK [11,12]. However, IGCC plants, that use coal in a combined cycle, are also examined here because they represent a potential advanced power technology for the UK. The most common forms of capture currently being developed are included in the assessment [11]. The PC and NGCC systems utilise globally used, post-combustion MEA absorption techniques [8-9,12]; whereas the IGCC plant is assumed to use the globally predominant physical, pre-combustion capture solvent known as ‘Selexol’.

A summary of potential CCS options for the UK is depicted in Table 2. The UK is an island nation, and the majority of the opportunities for CO₂ storage lie offshore. Transport of CO₂ will vary depending on the distance between the power station, where capture takes place, and the offshore storage facility. To provide a comparative assessment of each CCS system in the UK context, the transport requirements have been assessed from the largest, current power station: the coal-fired Drax station in the North East of England (in Yorkshire). Thus, the transport of CO₂ from this situation would require both onshore and offshore methods to potential storage sites. PC, NGCC, and IGCC plants are therefore all assumed here to be geographically located at the Drax site for comparison purposes.

It has been shown in previous economic studies that EOR and storage in depleted oil and gas wells are the most financially beneficial options, and they provide the highest degree of storage permanence. Estimates of safe geological storage beneath the Norwegian sector of the North Sea suggest about 600 years [9], although the gas leakage rate over such very long timescales has to be monitored and verified [3,14,16-17]. This study examines two storage options that appear feasible from the Drax location, and are employed as a ‘benchmark’ for UK CO₂ transport requirements (see Table 2). Firstly, EOR storage in the North Sea, which can exploit

Table 2: UK CCS options

Plant	Capture	Transport	Storage
PC	No capture: reference plant		
PC	Amine capture	Teeside/North Sea	EOR
PC		Humberside/North Sea	Depleted gas fields
NGCC	No capture: reference plant		
NGCC	Amine capture	Teeside/North Sea	EOR
NGCC		Humberside/North Sea	Depleted gas fields
IGCC	No capture: reference plant		
IGCC	Selexol capture	Teeside/North Sea	EOR
IGCC		Humberside/North Sea	Depleted gas fields

currently existing pipelines from Teesside. Secondly, storage in depleted gas fields off the coast of East Anglia, which can exploit currently existing pipelines from Humberside.

3.2 Drivers and Barriers to CCS Deployment in the UK

There are obviously a number of drivers and barriers to the UK deployment of CCS-ready power plants. In a Mini-Energy Report (state-of-science review) for the UK Government Office of Science, Gibbins and Chalmers [14] noted that none of the likely winners of the current Government-sponsored competition to build CCS demonstrators [20] would require scientific breakthroughs in order to achieve design solutions. But commercial deployment would require secure funding mechanisms to reward firms for carbon abatement via CCS, along with legal and regulatory frameworks for CO₂ transport and geological storage [14,17] (see also Section 2.4 above). Indeed, it has been observed that several of the industry representatives to the UK CCS stakeholder workshop organised (in May 2007) by Gough *et al.* [17] expressed concern over the perceived failure of the UK Government to provide sufficient enabling technology ‘push’ (see Fig. 1) across the entire CCS chain. The workshop participants identified a potential to reduce CCS costs of 50-75% by 2040. Greater financial incentives for carbon abatement need to be secured through a higher carbon price from the EU ETS. These were viewed as a critical factors for deployment, as well as reducing the energy penalty, achieving a niche for CCS in a more decentralised energy market, and technology transfer to rapidly-growing developing country markets (such as China and India) [17]. Beyond the consensus, a ‘vision’ was felt by stakeholders to be needed for what might constitute an onshore UK CO₂ transport network, and for the State (or the Crown) to take on the ownership and liability for long-term geologically stored CO₂ [17]. Chalmers *et al.* [21] recently adopted an innovative way to draw out lessons for the development of CCS in the context of the UK Government-sponsored competition [20]. They examined previous major UK ‘energy transitions’ [21]: the post-World War II development of nuclear electricity, the increase in size of pulverised coal power stations in the decade around 1960, the opening up of North Sea oil and natural gas fields in the 1960s and 1970s, and flue gas desulphurisation in the late 1980s and 1990s. In addition to the requirement for the sort of financial incentives for CCS deployment already outlined above [14,17], these historical transition studies provided a number of insights into critically important underpinning actions: the importance of active public engagement, together with the desirability of reviewing skills and capacity requirements [21].

3.3 UK CCS Techno-economic Appraisal

3.3.1 Power Plant Capture Costs and Energy Penalties

Technical performance details of the three types of power generators (indicated in Section 3.1 above), and associated CO₂ capture plants, were obtained from Parsons *et al.* [34]. The cost of electricity (COE) can then be used as an indicator of the impact of adding capture equipment on plant economics. It incorporates the costs of both the three power generation systems and associated CO₂ capture plants. The *Integrated Environmental Control Model* (version IECM-cs [35]), developed by Carnegie Mellon University for the US Department of Energy’s *National Energy Technology Laboratory* (DOE/NETL), provided the economic data for the power plants and CCS equipment. These sources have previously been widely used in connection with US studies [13, 36-38], as well as in the earlier appraisal of the thermodynamic and ‘exergoeconomic’ performance of NGCC plant with and without carbon capture by Hammond and Ondo Akwe [8]. They also formed the basis for the technical and cost data presented in the *Intergovernmental Panel on Climate Change* (IPCC) Special Report on CCS (SRCC) [3]. The COE {p/kWh} can consequently be determined using the following equation (adapted from Abanades *et al.* [38]):

$$\begin{aligned} \text{COE} &= \text{Fixed Costs} + \text{Fuel Costs} + \text{Other Variable Costs} \\ &= \{[(\text{TCR})(\text{FCF}) + \text{FOC}]/[(\text{CF})(8760)(\text{NPP})]\} + (\text{HR})(\text{FC}) + \text{VOC} \end{aligned} \quad (1)$$

This expression includes the following factors - TCR: total capital requirement {UK Sterling pence equivalent (p)}, FCF: fixed charge factor {fraction}, FOC: fixed operating costs {p}, CF: capacity factor {fraction}, 8760: total hours in a typical year, NPP: net plant power {kW}, HR: net heat plant rate {kJ/kWh}, FC: unit fuel cost {p/kJ}, and VOC: variable operating costs {p/kWh}. Thus, the levelised COE for all the potential UK power plants with and without capture can be obtained via Eq. 1 on a *pence per kilowatt-hour* basis (see Fig. 4). This data at 2005 price levels¹ indicates that NGCC systems are the cheapest electricity; both with and without capture. IGCC technologies exhibit a COE that is more expensive than PC systems without capture but, when capture is implemented, it becomes relatively less expensive. All of the plants show that when capture is added to the system the COE rises. PC plant COE increases by 84%, NGCC by 98% and IGCC by 36%. Percentage changes for PC and IGCC systems fall in line with earlier studies (for example, by Rubin *et al.* [13]), and this should be expected because the PC plant studied uses chemical absorption. In contrast, the IGCC system uses less energy and economically intensive physical absorption via an MEA solvent. However, the NGCC plant results in a very high percentage change, this is most likely because in this study it was also assumed to utilise a chemical (MEA) absorption process, whereas it is possible to use cheaper physical processes [9].

The effect of capture on plant efficiency is illustrated on Fig. 5 on a lower heating value (LHV), or ‘net calorific value’, basis. NGCC system is the most efficient with and without capture, followed by IGCC technologies, and then PC plants. The introduction of capture to the power plants clearly reduces the operating efficiency. The efficiency of the NGCC system is reduced the least (by 14% [8]), whilst IGCC plant efficiency is reduced by 16%. The greatest fall in efficiency occurs with PC plants by 30%. This is a significant reduction on the operating

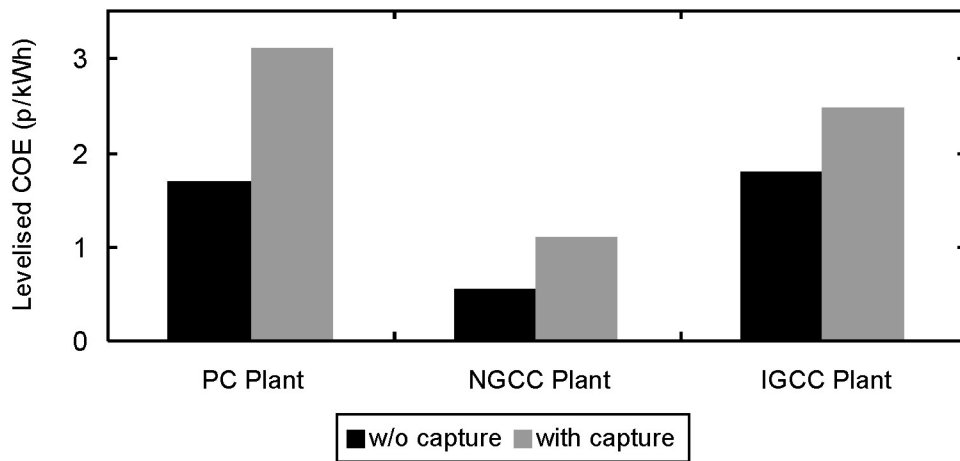


Fig.4. Power plant levelised cost of electricity (COE) with and without (w/o) carbon capture.

¹ 2005 is currently used as the base year for the compilation of the UK *Producer Price Index* (PPI), based on the output of manufactured products, by the *Office of National Statistics* (ONS) [see <http://www.statistics.gov.uk>]. The rate of PPI inflation over the 5 year period 2005-2010 (mid-year to mid-year), according to the ONS, has averaged 3.64% *per annum* (compound), or ~3.5% pa (with only a -1% error in PPI). Such time series information can therefore be employed to convert the 2005 price data given here to that related to other years of interest to particular readers.

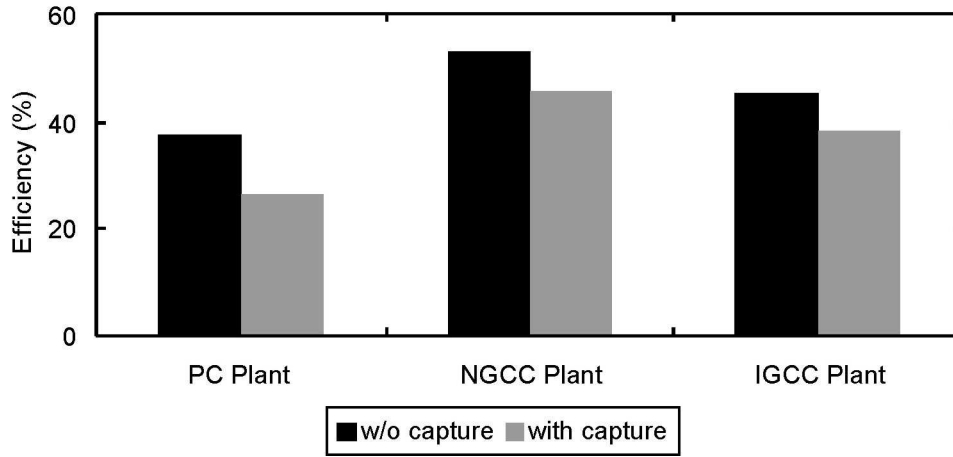


Fig. 5. Power plant efficiency with and without (w/o) carbon capture on a LHV basis.

efficiency.

Another indicator of CCS performance that is often employed to highlight the importance of the energy requirements of capture is the ‘energy penalty’ (in percentage terms { % variation from MW_{ref} }). This is the most commonly used metric (see Fig. 6) that can be determined using the following expression adapted from Rubin *et al.* [13]:

$$\text{Energy penalty} = [1 - (\text{Efficiency}_{cap} / \text{Efficiency}_{ref})] \quad (2)$$

It takes into account the net plant efficiencies with and without capture. Plants with capture have lower efficiencies, due to increased energy requirements inherent in the capture process. Efficiency values for the power stations can be used in Eq.2 to determine the associated energy penalties with capture. Fig 6 illustrates that the highest energy penalty is associated with PC plants; it is roughly double the value for NGCC or IGCC systems. The lowest energy penalty is associated with NGCC plants. It should be noted that the energy penalties in this assessment are lower than those in some previous studies. This suggests that the plants studied are particularly suited to the capture systems implemented.

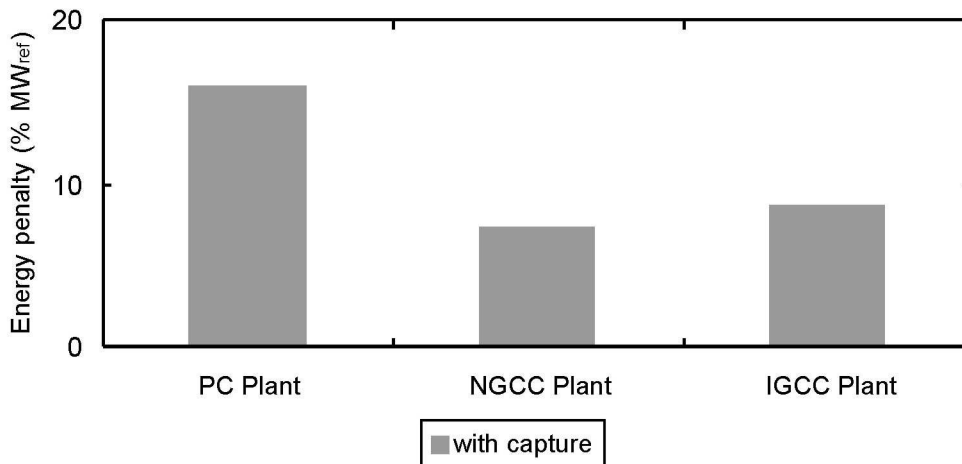


Fig. 6. Energy penalty of power plant associated with carbon capture.

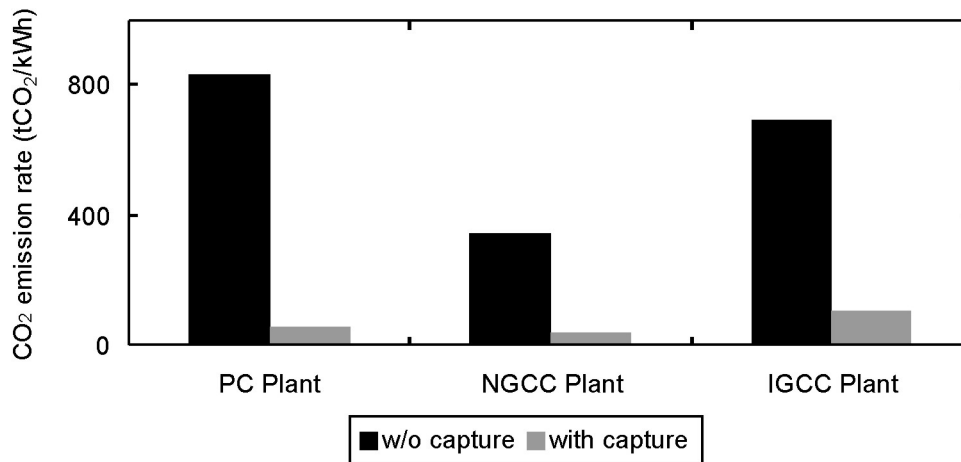


Fig. 7. Power plant CO₂ emissions with and without (w/o) carbon capture.

NGCC systems produce the lowest CO₂ emissions with and without capture (see Fig. 7), followed by PC plants, and then IGCC systems, even though the emissions from PC plants are higher than those of IGCC technologies without capture. This could be because the physical absorption process used in IGCC plants compromises the reduction of emissions, because it is not as effective a process as chemical absorption. In any case, all the emissions are reduced significantly: in PC plants by 93%, NGCC systems by 88%, and IGCC technologies by 85%.

3.3.2 Transport

The cost of transport of the CO₂ captured to the storage location is a combination of the distances involved and, more importantly, the quantities transmitted. The distance to the EOR storage site is considerably longer than that for the depleted gas fields; this would be a similar situation for the majority of power stations in the UK. The transport costs can be separated for the two different storage sites, but the costs for onshore and offshore transport for various quantities depending on the power plant have been averaged. Fig. 8 shows that the transport cost associated with EOR is higher than with the depleted oil fields: this was expected due to the notional

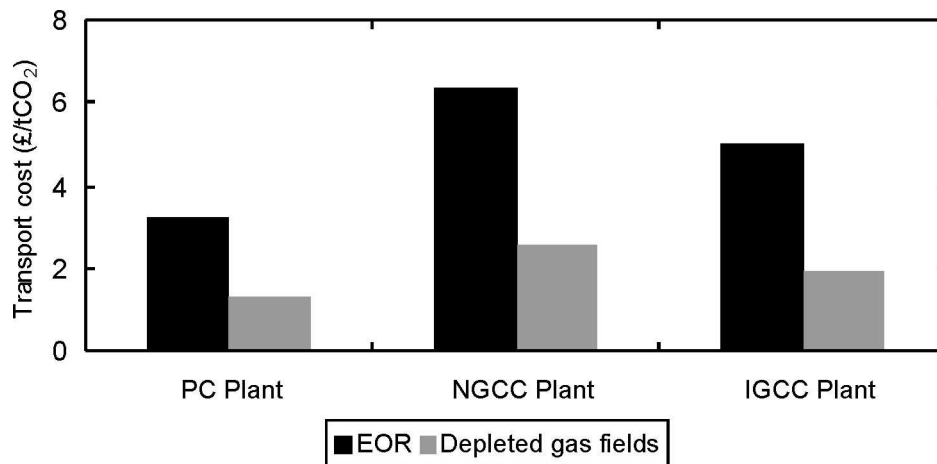


Fig. 8. Estimated average of CO₂ transport cost.

location of the power stations. They will obviously vary depending on the actual location of individual power stations, if CCS was implemented. It can be deduced from Fig. 8 that the two storage options for PC plants have the lowest transport costs; followed by IGCC systems, and then NGCC technologies. This is because the quantities involved in PC systems are the highest, due to the large amount of CO₂ gas captured. The same argument can be applied in the context of IGCC compared to PC plants. Piping CO₂ on a larger scale reduces the costs.

3.3.3 Storage

The cost of storage within the UK continental shelf will be very similar to EOR and gas field projects covered in earlier studies (e.g., Rubin *et al.* [13]). Therefore the storage costs can be taken directly from such studies as they provide experience of actual costs incurred. Fig. 9 shows storage costs for both the opportunities deemed currently viable in the UK. The three power station types would obviously incur the same storage costs. EOR can provide financial return from storage due to increased extraction of valuable oil. This revenue is dependent on the price of oil and therefore can deviate greatly.

3.3.4 Whole CCS Chain Assessment

In order to fully assess the potential of CCS in the UK over the ‘whole chain’, the individual costs from capture, transport and storage have been collated. The energy requirements of CCS increase the amount of fuel input (and consequently CO₂ emissions) of the entire chain [3]. A commonly used performance parameter for the effectiveness of capture systems is therefore the cost associated with the CO₂ emissions avoided. It reflects the net reduction of emissions and provides a cost for this environmental benefit. This is a widely used measure and indicates the average cost of reducing atmospheric CO₂ emissions using one CCS plant, while providing the same amount of useful product as a ‘reference plant’ without CCS. The ‘cost of CO₂ avoided’ {£/tCO₂} can be determined using the following equation [36-39]:

$$\text{Cost of CO}_2 \text{ avoided} = [(\text{COE})_{\text{cap}} - (\text{COE})_{\text{ref}}] / [\text{Emissions}_{\text{ref}} - \text{Emissions}_{\text{cap}}] \quad (3)$$

COE {£/kWh} is taken from the results estimated via Eq. 1 for capture (cap) and the reference plant (ref), as well as the mass emission rate {tCO₂/kWh}. The values of COE from Fig. 4 can therefore be used to determine the cost of CO₂ avoided via Eq.3 when capture is introduced. The results are presented in Fig. 10.

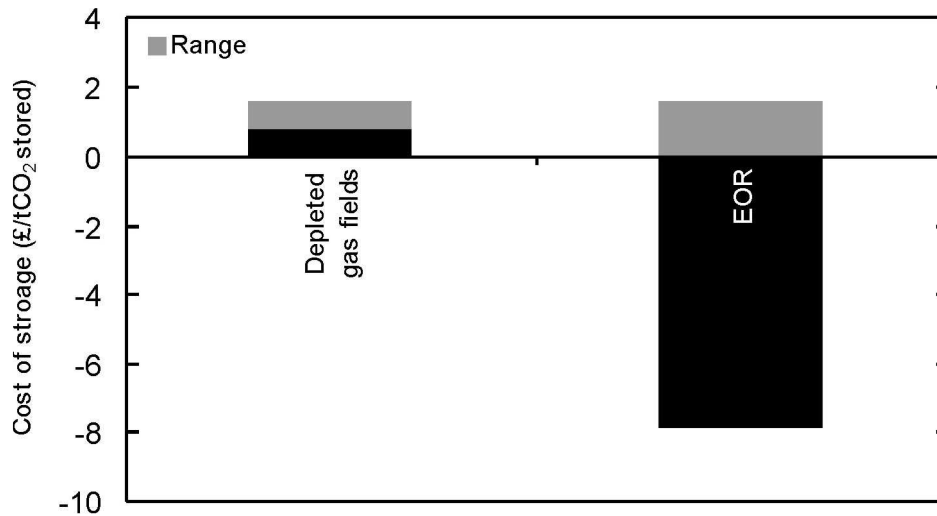


Fig. 9. Cost of CO₂ gas storage. [EOR: Enhanced Oil Recovery]

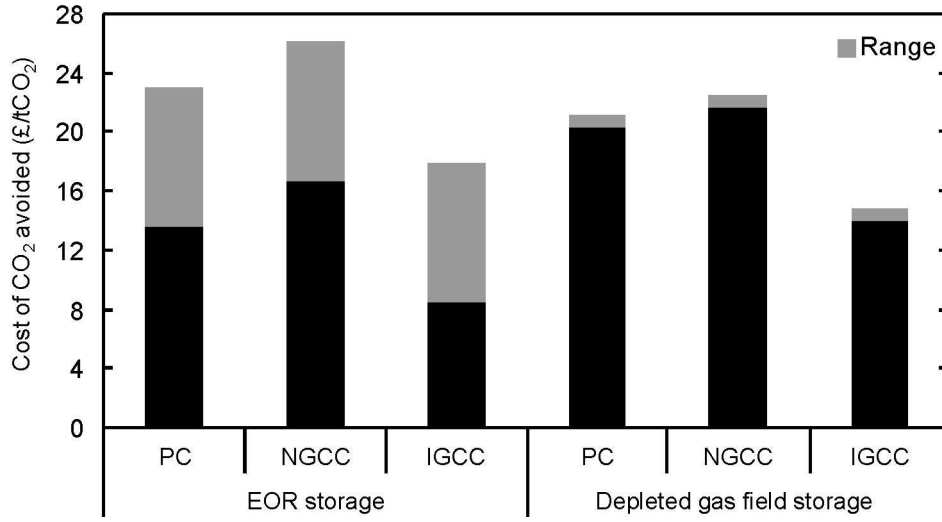


Fig. 10. Cost of CO₂ avoided by CCS plants on a whole chain basis.

Another indicator of capture performance is the cost associated with the CO₂ captured (see Fig. 11). It is also widely used, but is based on the mass of CO₂ captured as opposed to the emissions avoided. The ‘cost of CO₂ captured’ {£/tCO₂} is determined via the following expression:

$$\text{Cost of CO}_2 \text{ captured} = [(\text{COE})_{\text{cap}} - (\text{COE})_{\text{ref}}] / [\text{CO}_2 \text{ Emissions Captured}] \quad (4)$$

It includes the levelised COE {£/kWh} from Eq. 1 for capture (cap) and the reference plant (ref), as well as the mass of CO₂ captured {tCO₂/kWh}. Thus, the values of COE shown in Fig. 4 can be used in conjunction with Eq.4 to determine the cost of CO₂ captured from the CO₂ separation processes. Costs of capture can be employed to evaluate the potential of CCS against possible CO₂ emission penalties implemented by the Government. If the possible emission penalties reach the levels of carbon capture cost, then the COE would be same as for the reference plant. This study shows an average carbon capture cost of approximately £15/tCO₂ (see Fig. 11). The levels

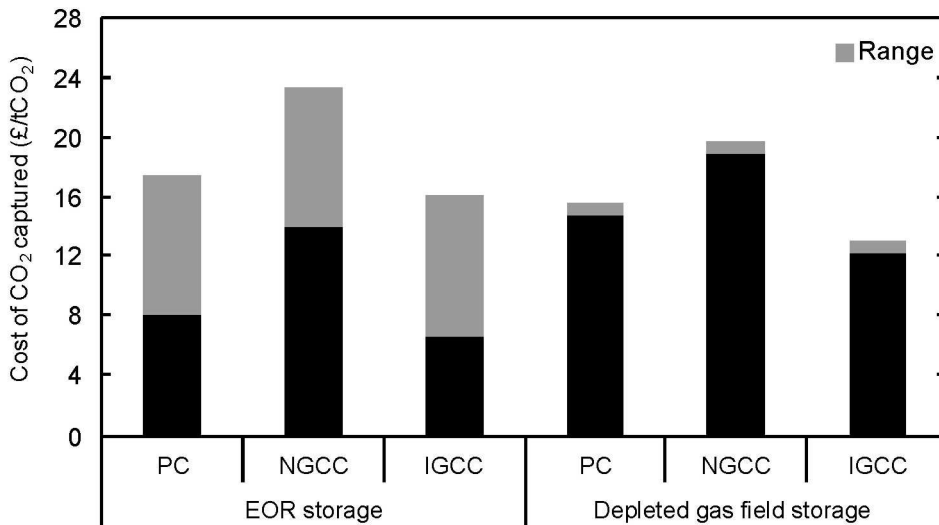


Fig. 11. Cost of CO₂ captured by CCS plants on a whole chain basis.

of potential CO₂ penalties may vary depending on the perceived ‘social cost of carbon’, which aims to evaluate the economic damage that climate change could cause to the Earth. However, the CO₂ penalties are likely to be determined by governmental bodies. Penalties of £27/tCO₂ (50 \$/tCO₂) have been suggested by the *International Energy Agency* (IEA). This would cover the costs of CO₂ capture in all the UK power plant and capture technologies examined here. Fig. 10 and Fig. 11 show that the cost of avoiding CO₂ and the cost of capture follow similar trends. The ‘cost of CO₂ captured’ is lower than the cost of CO₂ avoided, as a rule. Costs of CO₂ avoidance/capture are lowest for IGCC technologies, followed by PC plants and are most expensive for NGCC systems. The significant range for EOR depends upon the financial revenues incurred from additional oil extracted.

A very useful indicative assessment metric for CCS schemes is how they affect the end product in terms of the COE on a whole CCS chain basis. Fig. 12 depicts the levelised COE for each power plant /capture technology combination considered here for the UK. In the case of PC plants, CCS with EOR results in an increase of COE compared to the reference system of 62-106%, whereas CCS in gas wells leads to a 93-97% increase. For NGCC technologies, CCS with EOR results in an increase of 91-142% and CCS with gas well storage give rise to an 118-122% increase. IGCC plants with EOR result in an increase of 27-60% and CCS with gas well storage incur a 45-48% increase. The average price increase for all scenarios is about 84%. Thus, the COE of NGCC remains the lowest with and without CCS, even though it has the highest percentage rise in cost. A key point to note is that even though IGCC has a higher reference system COE than PC plants, the COE of IGCC with CCS is lower than PC with CCS. The rises in COE are significant, but could be reduced as the technologies develop in the future reflected in so-called ‘learning or experience curves’ [26-28] (see again Fig. 3).

Participants in the UK CCS stakeholder workshop organised by Gough *et al.* [17] argued that greater financial incentives for carbon abatement are required through a higher carbon price from the EU ETS and the industry representatives expressed concern over the perceived failure of the UK Government to provide sufficient enabling technology ‘push’ (see Fig. 1) across the entire CCS chain. They also identified a potential to reduce CCS costs of 50-75% by 2040. Indeed Scrase and Watson [29] recently observed that the UK Government’s own estimates of power plant/CCS costs fell by 24-36% between 2006 and 2007, although they assert that this might be

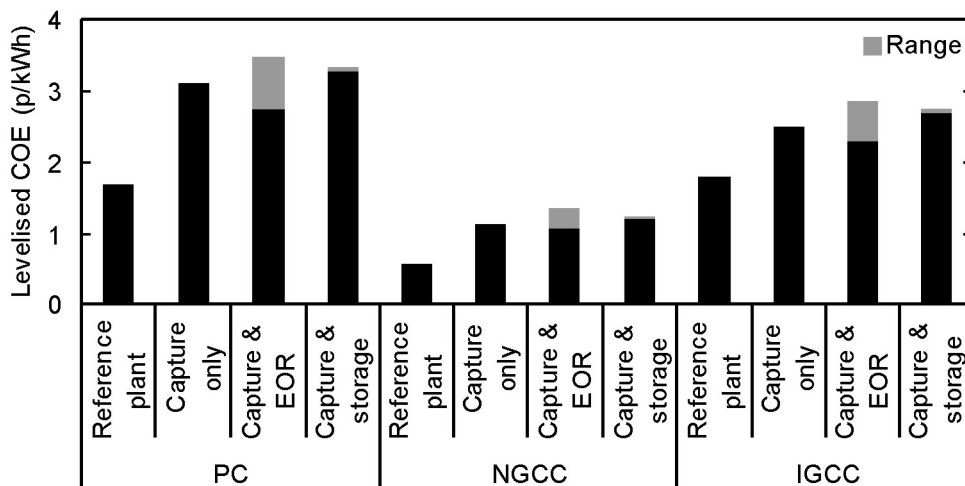


Fig. 12. Levelised cost of electricity (COE) on a whole CCS chain basis.

due to ‘appraisal optimism’ by decision-makers and developers. In any case, these are critical factors for deployment (see Section 3.2 above), as well as for reducing the energy penalty, achieving a niche for CCS in a more decentralised energy market, and technology transfer to rapidly-growing developing country markets (such as China and India) [17]. But this technology needs to compete with other carbon abatement options. Watson [39] collated data on the alternative CO₂ abatement options derived from the UK Cabinet Office’s Energy Review [40] by the then *Performance and Innovation Unit*. He indicated that, for example, household energy efficiency measures would cost between -£300 and +£50/ tCO₂ abated, whilst comparable onshore wind farm costs would be between -£80 and +£50/ tCO₂, and nuclear power costs would be between +£70 and +£200/ tCO₂ abated. They can be contrasted with the present power plant/CCS estimates for the cost of CO₂ captured with EOR storage (see Fig. 11) of between +£7 and +£24/tCO₂ abated. Comparable UK Government 2003 whole chain power plant/CCS estimates, according to Watson [41], were between +£28 and +£35/tCO₂ abated. However, Scrase and Watson [29] lately observed (as noted above) that power plant/CCS costs have fallen significantly over recent years. It can therefore be seen that fossil-fuelled power stations with CCS have a large potential financial advantage over nuclear power plant, but efficiency measures (and even wind turbines) are more economic carbon abatement options in most cases.

4. CONCLUDING REMARKS

The 2007 Energy White Paper (EWP) [41] accepted that Britain should put itself on a path to achieve a goal by adopting various low-carbon options, principally energy efficiency measures, renewable energy sources, and next generation nuclear power plants. Technologies for carbon capture, or sequestration, were also identified as an important element in any energy RD&D programme (see also the recent report of the UK *Energy Research Partnership* [32]; a high-level, public-private forum bringing together key stakeholders and funders of energy RD&D). EWP targets for new renewable electricity supply were set at 10% by 2010 and 20% by 2020. It is going to be difficult for renewables (principally wind) to fill the perceived ‘electricity gap’ [6]. The UK Government is supportive of building a new generation of nuclear reactors to replace those currently undergoing decommissioning [41]. This, together with carbon capture and storage (CCS) technologies and renewables, are likely to be their preferred route to a decarbonised power generation system [6,32]. It has been argued here that CCS coupled to fossil-fuelled power plants is a climate change mitigation option that potentially permits the continued use of fossil fuels, whilst reducing the carbon dioxide (CO₂) emissions. The Government has stated in its 2009 *UK Low Carbon Transition Plan* [42] that it intends to support the construction of up to four CCS demonstrators linked to coal-fired power stations by 2014-2015. In addition, it proposed to place a requirement on any new coal power stations to demonstrate this technology. The limitations to this strategy, which involve an element of ‘picking winners’ (via the UK Government’s CCS demonstrator competition, based only on post-combustion capture technologies), were recently discussed by Scrase and Watson [29]. They also note that the uncertainties over full-scale power plant CCS technical performance and costs may only become clearer when the first demonstrators are operational in perhaps five years time. The present study has attempted to reduce these uncertainties by way of indicative estimates of the techno-economic performance of six possible UK power plant/CCS chain options over their whole chain: from power stations to typical storage reservoir. It is clearly important to reduce energy demand in the UK and elsewhere. This could be achieved, in part, by the array of methods available to improve the efficiency with which energy is produced and consumed [10,43,44]. That would mitigate against climate change and enhance energy security. But on the supply side the situation is more complex. In the period leading up to 2050, the UK electricity network is likely to be more decentralised, although the extent of that is a matter of debate. The choice of power technology will not just be determined by economic factors, and the way in which they

dynamically interact with a smart grid and consumer demand will also be critically important issues.

The carbon capture and storage process involves three basic stages; capture, drying and compression of CO₂ from power stations, transport of CO₂, and storage away from the atmosphere for hundreds to thousands of years. The UK has a potential storage capacity of some 20-260 GtCO₂ [11]; this would be equivalent to over 100 years of current fossil fuel CO₂ emissions. Potential routes for the dehydration, capture, transport and storage of CO₂ from UK power stations have been examined². Six possible CCS options were evaluated, based on Pulverised Coal, Natural Gas Combined Cycle, and Integrated (coal) Gasification Combined Cycle power stations. Chemical and physical CO₂ absorption capture techniques were assumed to be employed with realistic transport possibilities to Enhanced Oil Recovery (EOR) sites or depleted gas fields in the North Sea. Selected mature (rather than ‘first of a kind’) technological options have been quantitatively assessed to yield well-established, indicative economic and energy-related criteria. Results show that CO₂ capture can reduce emissions by over 90% (see Fig.7). The average cost of storage for the UK CCS options (Fig. 8) was £1.2/tCO₂ for depleted gas fields and a financial return of £3.2/tCO₂ for EOR, which could offset the majority of the transport costs. [These, and other monetary values, determined in the present study are given in terms of 2005 prices: the current base year for official UK producer prices. Estimates for subsequent years can be made using the ONS time series for the PPI; thereby taking account of producer price inflation.] Watson [41] observed that comparable UK Government figures for 2003 were £1.0/tCO₂ for depleted gas fields and a financial return of £7.0/tCO₂ for EOR respectively. Total CCS ‘cost of CO₂ avoided’ is greatest for NGCC systems followed by PC plants. IGCC technologies are the cheapest to avoid CO₂ emissions. However, this will reduce the efficiency of the power plants concerned, incurring energy penalties between 14-30% compared to reference plants without capture (Fig. 6). This range is towards the lower end of some earlier studies [15], although in line with others [5,8,13] and higher than some [12]. Costs of capture, transport and storage have been concatenated to show that the cost of electricity with CCS implemented rises by 27-142% (Fig. 12), depending on the power plant/CCS option. This is a significant cost increase, although calculations show that the average ‘cost of CO₂ captured’ is £15/tCO₂ (Fig. 11); range £7-£24/tCO₂ abated. If potential governmental CO₂ emission penalties were introduced at around this level, then the cost of electricity would equate to the same as the reference plant and make CCS a viable option to help mitigate large-scale climate change.

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² Readers wishing to consult CCS roadmaps with application beyond the UK may consult the recent report by the IEA [45]. See also the review by Orr [16].

consortium of university partners (with Prof. Peter Pearson, an energy economist, now Director of the *Low Carbon Research Institute* in Wales) funded via the strategic partnership between *e.on* UK (the electricity generator) and the EPSRC to study the role of electricity within the context of ‘*Transition Pathways to a Low Carbon Economy*’ [under Grant EP/F022832/1]. Prof. Hammond is grateful to all these colleagues for their role in the co-ordination of large consortia of university and other partners. The third author (SW) wishes to thank the *Gloucestershire County Council* and the *Higher Education Funding Council for England* for financial support of his studies. However, the views expressed in this paper are those of the authors alone, and do not necessarily reflect the views of the collaborators or the policies of the funding bodies. The authors wish to acknowledge the care with which Gill Green (Department of Mechanical Engineering, University of Bath) prepared the figures.

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ABBREVIATIONS AND NOMENCLATURE

CCS Carbon (dioxide) capture and storage

CF Capacity factor {fraction}

CO₂ Carbon dioxide

COE Cost of electricity

DOE US Department of Energy

ECBM Enhanced coal-bed methane

EGR Enhanced gas recovery

EOR Enhanced oil recovery

ETS EU Emissions Trading Scheme

EU European Union

FC Unit fuel cost {p/kJ}

FCF Fixed charge factor {fraction}

FOC Fixed operating costs {p}

GHG Greenhouse gas

HM Her Majesty's

HR Net heat plant rate {kJ/kWh}

IEA International Energy Agency

IECM	Integrated Environmental Control Model [developed by Carnegie Mellon University for the US DOE's NETL]
IGCC	Integrated coal gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
LHV	Lower heating value ['net calorific value' in British terminology]
MEA	Mono-ethanolamine
NETL	US DOE's National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NO _x	Nitrogen oxide(s)
NPP	Net plant power {kW, or equivalent (e.g., MW)}
OECD	Organisation of Economic Co-operation and Development
ONS	UK Office of National Statistics
pa	per annum
PC	Pulverised coal-fired steam cycle
PPI	UK Producer Price Index
R&D	Research and development
RD&D	Research, development and demonstration
SRCC	IPCC Special Report on CCS
TCR	Total capital requirement {UK Pound Sterling (£), or equivalent [e.g., pence (p)]}
UK	United Kingdom of Great Britain and Northern Ireland
US	United States of America
VOC	Variable operating costs {p/kWh}

Subscripts

cap	Capture (power plant with CCS)
ref	Reference (baseline power plant without CCS)